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ESTABLISHMENT OF NATIONAL EMISSION STANDARDS FOR STATIONARY SOURCES. VOLUME II. STEAM ELECTRIC POWER GENERATION

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ESTABLISHMENT OF NATIONAL EMISSION STANDARDS FOR STATIONARY SOURCES

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STEAM ELECTRIC POWER GENERATION

1.0 INTRODUCTION

The power industry is widely recognized as a major source of air pollution contributing large amounts of particulate matter, sulfur oxides (SO_x), and nitrogen oxides (NO_x), with small amounts of carbon monoxide (CO) and hydrocarbons (HC) also emitted. Table 1 gives estimates of nationwide emission levels for these pollutants (data taken from Refs. 1 through 6). The consumption of power in the U.S. has essentially doubled over each decade for the past thirty years and this trend is likely to continue to the end of the century (Ref. 7). In 1966, approximately 32×10^{15} BTU of energy, or about 38% of the U. S. total, was consumed by the power generation industry. Fig. 1 shows the projected electric power generation capacity for the U.S. by various fuel sources. It is seen from this projection that coal, oil, and gas will be significant sources of energy for some time. Without abatement or controls, the pollution from combustion of these fuels in the power generation industry would be expected to increase past the year 2000 according to the increase in their use.

In the following presentation on status of emission regulations and control technology, separate treatment is given to the three major pollutants: particulates (and visible emissions), SO_x, and NO_x. Some control processes, however, affect more than one pollutant; this is recognized when appropriate.

TABLE 1

ESTIMATES OF NATIONWIDE EMISSIONS OF POLLUTANTS FROM STEAM ELECTRIC POWER GENERATION FOR 1968

Pollutant	All Sources[a] (millions of tons/yr.)	Total Stationary Combustion Sources (millions of tons/yr.)	Power[b] Generation (millions of tons/yr.)	Proportion (%) of Total (all sources) from Power Generation
Particulates	28.3	8.9	5.8	21
Oxides of Sulfur	32.8	24.0	14.0	43
Oxides of Nitrogen	20.6	10.0	4.2	20
Hydrocarbons	32.0	0.7	<0.3	<1
Carbon Monoxide	100.1	1.9	<0.8	<1

[a] Data from Ref. 6.

[b] Values estimated by using percentage of stationary combustion source emissions contributed by power generation as compiled from data given in Refs. 1 through 5 and applying these to the estimates for stationary combustion sources listed above.

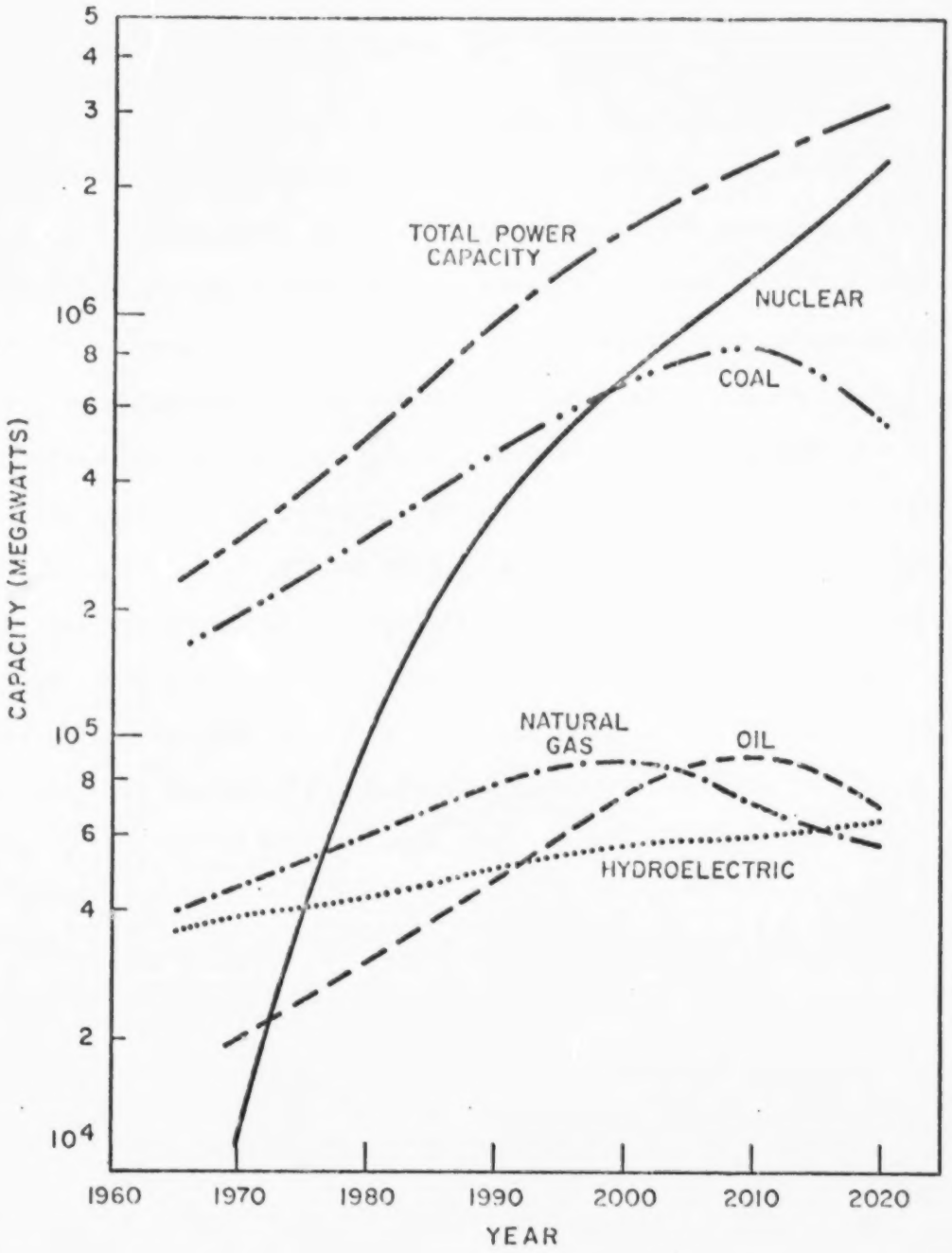

Fig. 1. Projected power generating capacity and fuel sources of electric utilities in the United States (with breeder). NAPCA, February 1970. (Graph taken directly from Ref. 8).

2.0 PARTICULATE (AND VISIBLE) EMISSIONS

As was shown in Table 1, the power generation industry contributed in 1968 about 20% of the total of all particulates emitted in the U.S. In addition to being a major source of particulates, the power industry has been a leader in stimulating the development of and utilizing particulate pollution control systems. In 1966, 86.5% of the particulates generated by the power industry were collected and did not enter the atmosphere (Ref. 1).

Estimates of particulate emissions from power generating plants for the year 1966 are given in Table 2. Estimates of both uncontrolled emissions and actual emissions are given for generating plants burning coal, oil, and gas. Note that existing control of particulate emissions from oil and gas-fired boilers is negligible. The control of particulate emissions from coal-fired boilers in 1966 was 86.5%. The use of coal-fired boilers in the power industry has doubled every 10 years (in terms of BTU heat input) and this trend is expected to continue past the year 2000 (see Fig. 1).

TABLE 2

ESTIMATED PARTICULATE EMISSIONS IN POWER GENERATING INDUSTRY IN YEAR 1966 (REF. 1)

	Emissions if Uncontrolled 10^6 tons/year	Estimated Emissions with Controls 10^6 tons/year
Anthracite coal	0.17	0.02
Bituminous and lignite coal	21.14	2.85
Oil	0.03	0.03
Gas	0.02	0.02

2.1 Emission Levels

Uncontrolled particulate emissions factors are given in Table 3. These emission factors allow an estimation of the amount of uncontrolled particulate emissions based upon the type of fuel to be burned, the capacity rating, and efficiency. For example, a 1000 MW generating plant operating at approximately 30% efficiency would require 104 million BTU heat input per hour. Assuming that the fuel used is pulverized coal with an ash content of 10%, then the amount of uncontrolled particulates or fly ash generated will be 6.9 lbs. per million BTU input, or a total of 69000 lbs. of fly ash per hour. If this is passed through an electrostatic precipitator which removes 99% of the particulates, the emissions will be 690 lbs. per hour.

Note that the uncontrolled particulate emissions for generating stations burning oil or gas would be only 0.069 and 0.015 lbs./10^6 BTU heat input respectively. Both levels of emission are equal to or below the most stringent existing or proposed regulation for total particulates for generating stations with capacity rating below approximately 1550 MW in the case of oil (see Fig. 2), and approximately 20,000 MW in the case of gas.

The distribution of fly ash particle size has a maximum at about 20μ. Measurable quantities of particulates cover a size range of from 1μ to 300μ. The peak of the size distribution is shifted downward to about 10μ when passed through a mechanical collector (Ref. 26).

Table 3

PARTICULATE UNCONTROLLED EMISSION FACTORS (Ref. 1)

	Uncontrolled Particulate Emission Factors ($lb/10^6$ BTU heat input)
Coal	
Pulverized firing	0.69A
Cyclone firing	0.08A
Oil	0.069
Gas	0.015

* A = percent ash content

2.2. Regulation on Particulate Emissions

Regulations which constrain the emission of various air pollutants into the atmosphere must take into account the state-of-the-art in the applicable control technology as well as the cost of control system and the value of the product involved. The control of particulates in the power generating industry is at least as well understood as any other area of air pollution control. Some existing regulations reflect these considerations. For example, in New York City, the regulation on particulates is written in terms of control efficiency rather than in terms of particulate emissions. More specifically, the regulation states that control efficiency must equal or exceed 99%.

The uniform regulation (i.e., one independent of plant capacity) existing in New York City is the only regulation in the U. S. at present which is expressed in terms of collection efficiency. Excluding those in New York City the most stringent regulations in the U. S. at present are shown in Figure 2. Below about 1500 million BTU heat input per hour

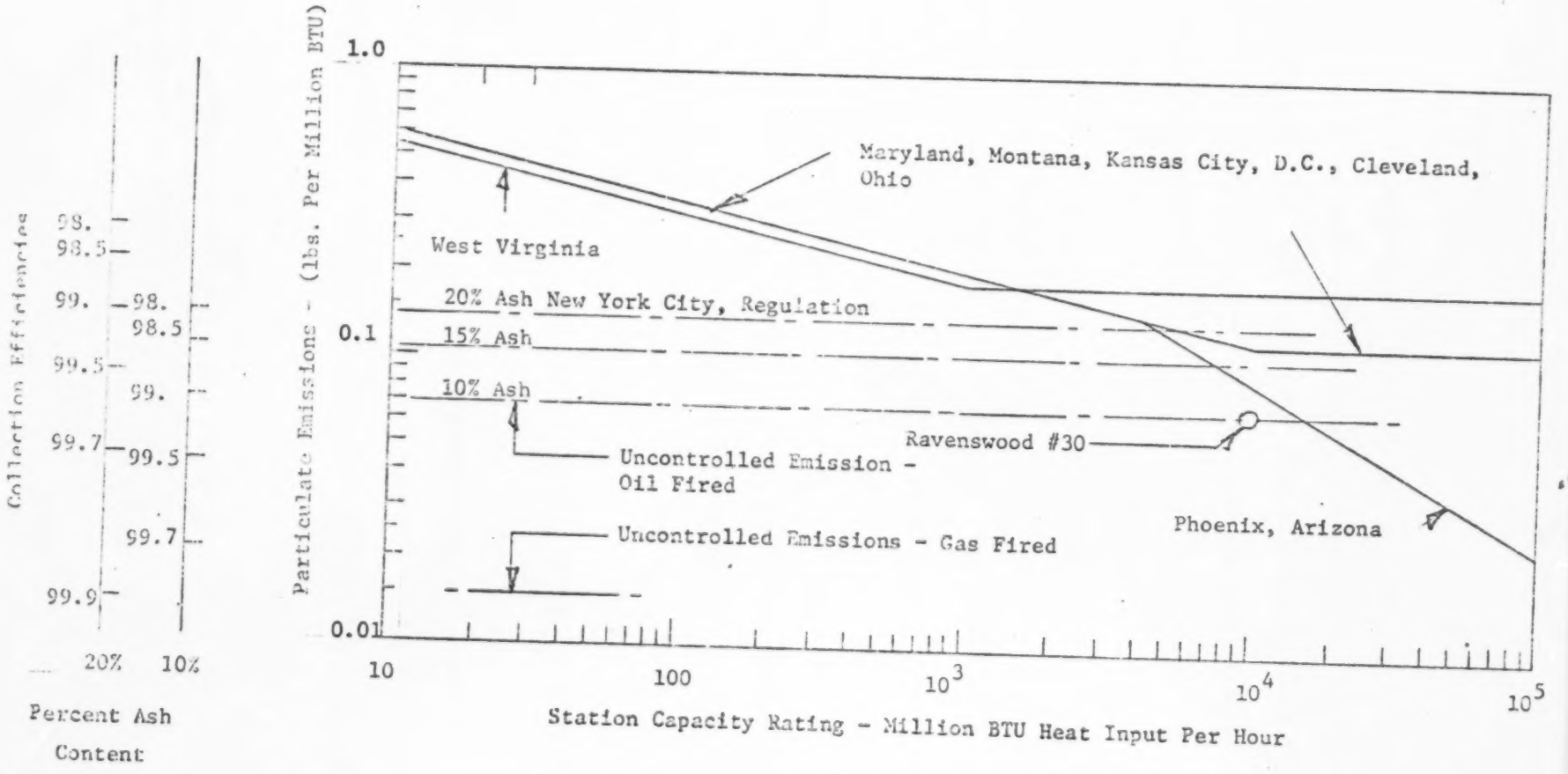

Figure 2. Regulations on Particulate Emissions in Power Generating Industry.

(or approximately 150 MW), regulations existing in West Virginia are the most stringent. Above this capacity rating, regulations existing in Phoenix, Arizona are the most stringent. Note that for capacity ratings above 1500 and below 4000 million BTU heat input per hour, the regulations existing in Maryland; Montana; Kansas City; D.C.; Cleveland, Ohio; and Phoenix, Arizona are identical. With the exception of the Phoenix code, all of the regulations in Figure 2 become uniform for capacity ratings exceeding a specified value. In the case of the Phoenix code for plants exceeding 4000 million BTU heat input capacity ratings, the degree of particulate removal which is required increases at a greater rate than is the case for plants of less than 4000 million BTU input heat capacity ratings.

The two scales on the left in Fig. 2 give the collection efficiencies required to achieve specific levels of particulate emissions from coal-fired boilers. The scales are applicable to coal containing either 10% ash or 20% ash. For example, if a station is burning coal containing 20% ash and its particulate emissions cannot exceed 0.09 lb. per BTU, then the station must be equipped with a particulate collector that is very nearly 99.5% efficient.

Regulations on visible emissions are generally stated in terms of shade and opacity. For example, the Arizona State Department of Health has the following code on the emission of visibles into the atmosphere.

> Reg. 7-1-2.1 SHADE, DENSITY OR OPACITY OF EMISSIONS
>
> No person shall cause, suffer, allow or permit the discharge into the atmosphere from any single source of emission whatsoever any air contaminants for a period or periods aggregating more than three minutes in any one hour which is:

1. As dark as, or darker in shade than that designated as No. 2 on the Ringelmann Chart as published by the U.S. Bureau of Mines, or

2. Of an opacity equal to or greater than an air contaminant designated as No. 2 on the Ringelmann Chart.

Another example of emission visible and the most stringent regulation has been proposed by the Maryland State Department of Health and Mental Hygiene with the pertinent sections of the code stated as follows:

_____01 CONTROL AND PROHIBITION OF VISIBLE EMISSIONS FROM INSTALLATIONS

_____0101 Visible Emissions. No person shall cause, suffer, allow or permit the discharge of emissions from any installation or building, other than water in an uncombined form, which are visible to human observers.

2.3 Control Technology

There are four basically different systems for the control of particulate air pollutants. These are mechanical collectors, fabric filters, wet scrubbers, and electrostatic precipitators. There are a number of very good articles and reports describing and comparing particulate control systems (e.g., Ref. 1). With respect to the control of particulates in the power generating industry, electrostatic precipitators frequently used with mechanical collectors are the most common type of control system. Mechanical collectors alone are not efficient enough to satisfy existing and proposed particulate regulations. Although fabric filters can achieve the desired collection efficiencies, their poor reliability and uncertain performance have limited their application in the power industry. Considerable research and development has also been directed toward utilizing wet scrubbers. The economic feasibility of using

wet scrubbers for the removal of particulates has not been demonstrated (Ref. 29). However, as described in Section 3.3, some of the wet scrubbers under development for SO_2 removal from flue gases have also shown particulate removal efficiencies greater than 99%. The capability of wet scrubbers, when needed for SO_2 control, may thus preclude the need for a precipitator. Thus, at present the electrostatic precipitator represents the only approach which is both economically feasible and gives collection efficiencies which are required in meeting existing and proposed particulate emission regulations.

Electrostatic precipitaters have been used in the power generating industry for over 30 years. Early in this period collection efficiencies were typically 75%. At present, a number of large electrostatic precipitators are being designed with collection efficiencies in excess of 99% and are being installed at power generating stations throughout the U.S. The precipitator installed at Ravenswood Unit 3 of the Consolidated Edison in New York, New York represents the best operating particulate control system in the power industry. The Ravenswood Unit 3 station is a 1000 MW, two-boiler, coal and oil-fired generating system. The station was partly operational on oil in 1967 and fully operational on coal and oil in 1969. The electrostatic precipitator and mechanical collector installed at Unit 3 were manufactured by Research Cotrell, Inc. Brief descriptions of both the mechanical collector and electrostatic precipitator are presented in Ref. 27 and are reproduced in the following table:

Description of Mechanical Collector and Electrostatic Precipitator at Ravenswood Unit 3

Mechanical Collector	Multi-tube, cyclone-type collector consisting of 1264 10-in. diameter Cyclo-trell collecting tubes per precipitator, or a total of 5056 tubes for the entire installation.
Electrostatic Precipitator	Four individual precipitators, each comprised of four units containing eight electrical sections each. Each contains 35 electrostatic ducts. Sixty-four 70-KVP, 750-MA electrical sets consisting of silicon diode rectifiers tanked with transformer. One hundred and twenty-eight bus sections supplying half-wave rectified voltage to the precipitators.

Saturable core reactors	64
CAS automatic control units	64
Electric plate rappers	320
Electric wire vibrators	120

Collecting area	1,008,000 ft^2
Collecting area per 1,000 CFM of gas	234 ft^2
Bus sections per 100,000 CFM of gas	2.98
Velocity through precipitator	5.67 ft per sec
Treatment time	5.30 sec.

This particular installation is of importance for the following reasons:

(1) The system has been operational for nearly two years and its performance has been evaluated.

(2) The electrostatic precipitator is designed to collect fly ash from low-sulfur coal (<1% sulfur content).

(3) Fly ash from both coal and oil are collected efficiently.

The design performance data and guarantee conditions for mechanical collector and electrostatic precipitator are given in the following tables:

PERFORMANCE DATA

Gas flow, CFM at 700F	4,300,000	3,230,000	2,150,000
Precipitator efficiency,%	99.2%	99.8%	99.9%
Mechanical collector efficiency, %	59%	47%	2%
Guaranteed overall efficiency, %	99%	99%	99%

Draft loss, inches of water

Flues and Electrostatic Precipitators	3.75
Collector	2.50

GUARANTEE CONDITIONS

Gas	4,300,000 CFM at 700F 750 F maximum
Fuels	Coal - Pulverized bituminous Gas - Sweet natural Oil - Residual fuel oils now commercially available in Port of New York and heavier residuals to 1500 S. S. F.
Dust	Inlet loading - 0.5 to 2.5 grains per cu ft of gas at 700 F Combustible - From 0.2 to 25% by weight on dry basis Sulfur - From 0.6 to 3.0% by weight on dry basis

Since the Ravenswood Unit 3 became operational in early 1969, two tests have been performed to determine precisely the particulate collection efficiency. The measured collection efficiencies were 99.6% and 99.2% (Ref. 28). As indicated in the preceding, the electrostatic precipitator was designed to collect fly ash from coal with low sulfur content as required by New York air pollution regulation. Electrostatic precipitators are usually operated down stream from the air heaters in the boiler system;

the gas temperature at this point is approximately 300°F. At this temperature, the electrical resistivity of fly ash increases very rapidly as the sulfur content of the coal is reduced. This increase in resistivity significantly degrades the operation of electrostatic precipitators. At temperatures higher than approximately 500°F and lower than approximately 250°F, the electrical resistivity of fly ash is essentially independent of the sulfur content of coal. Thus, the electrostatic precipitator at Ravenwood Unit 3 has been designed to operate between the boiler and the air heater at a temperature of about 700°F. This high temperature also allows effective collection of ash from both coal and oil.

The cost of the electrostatic precipitator and mechanical collector was approximately 5 million dollars including installation. The cost of fly ash handling equipment (conveyors, storage, and unloading equipment) and steel supporting structures for the entire particulate removal system was in excess of 5 million dollars. Thus, the entire system cost was slightly in excess of 10 million dollars (Ref. 28). Using formulas and approximations in Ref. 1, the annual maintenance and annual operating costs are estimated to be $90,000 and $450,000 respectively. It is stressed that these annual maintenance and operating costs are estimated and have not been verified by Consolidated Edison.

3.0 SULFUR OXIDES

Sulfur oxides appear as an air pollutant in the power generation industry solely as a result of burning sulfur bearing fuels. It appears mainly as SO_2 with considerably smaller amounts of SO_3*. Projections for SO_2 emissions without future abatement or control is shown in Fig. 2. The relative contributions to total SO_2 emissions in the U.S. by coal, oil, and gas combustion in the power utilities (1966 data) are given in Table 4. Even though about 20% to 25% of the electric power in the U.S. is generated by gas combustion, the relative amount of SO_2 contributed by gas is small because only very minor amounts of sulfur are contained in gas.

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*Combustion of sulfur bearing fuels produces about 2 pounds of SO_2 and about 0.03 pounds of SO_3 for each pound of sulfur in the fuel. Because of the proportionately small share of SO_3 and because most measurements and regulations are made in terms of SO_2, only SO_2 is treated in the remainder of this section.

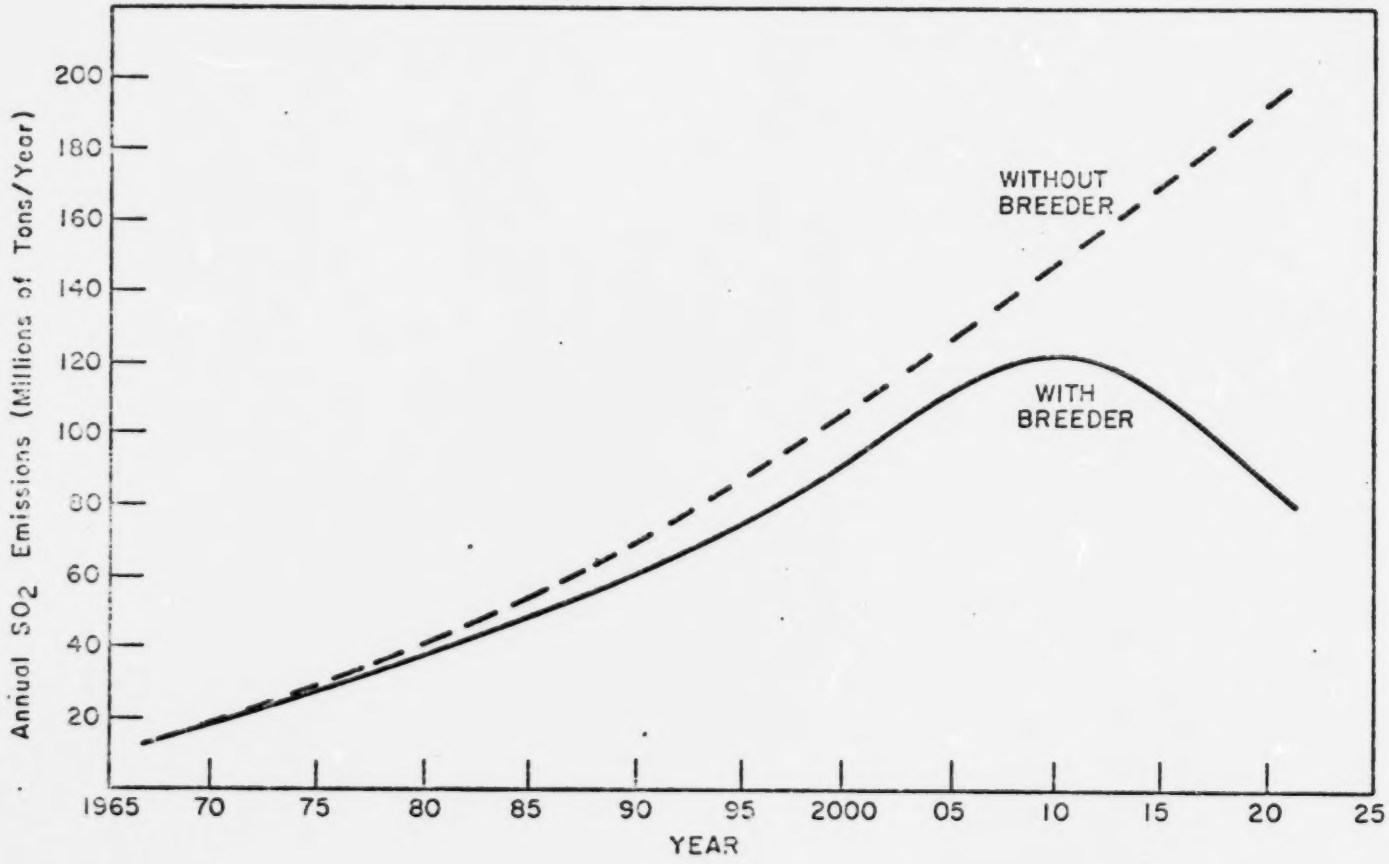

Fig. 3. Comparison between projections for total power plant uncontrolled SO_2 emissions. NAPCA, February 1970 (Graph taken directly from Ref. 8).

TABLE 4

SO_2 EMISSIONS FROM POWER UTILITIES IN THE U.S. IN 1966 (REF. 2)

	Emissions in Tons	% of Utilities Total
Coal	11,925,000	90.7
Oil	1,218,000	9.3
Gas	3.500	Negligible

3.1 Emission Levels

Emission factors for coal, oil, and gas combustion are listed in Table 5. Typical emission levels as a function of electric generating plant size are shown in Fig. 4 which were computed from emission factors and fuel heat values of 13,000 BTU per pound of coal, 150,000 BTU per gallon of oil, and 1,000 BTU per cubic foot of gas. Most steam electric power generation plants for public utilities have ranged in size from 100 MW (approximately 10^3 million BTU/hr* heat input) to 1,000 MW (approximately 10^4 million heat input). For coal-fired units burning 2% sulfur coal, SO_2 emissions thus range between 3,000 and 30,000 pounds per hour or between 12,000 and 120,000 tons per year. Note that 3% sulfur oil would yield about the same SO_2 emission levels as 2% sulfur coal; however, SO_2 emissions from natural gas are lower than either of these by four orders of magnitude.

Many new steam electric generation plants are designed for power capacities of greater than 1,000 MW. When fired with coal or oil, the potential SO_2 emissions are very large, and the need for controls on these large point sources becomes obvious.

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*The rule-of-thumb conversion of 1 MW per 10 million BTU/hr heat input is used throughout this section and is based on an overall plant efficiency of 34.1%, which is fairly representative of units in existence. New installations may have efficiencies up to 40%.

TABLE 5

SO_2 EMISSION FACTORS FOR COMBUSTION SOURCES (REF. 9)

Fuel Type	Emission Factor
Coal	38S[/a] pounds per ton of fuel
Oil	157S[/a] pounds per 1,000 gallons of fuel
Gas	0.4 pounds per million cubic feet of natural gas

[/a] S is a multiplying factor representing the percent sulfur by weight in the fuel.

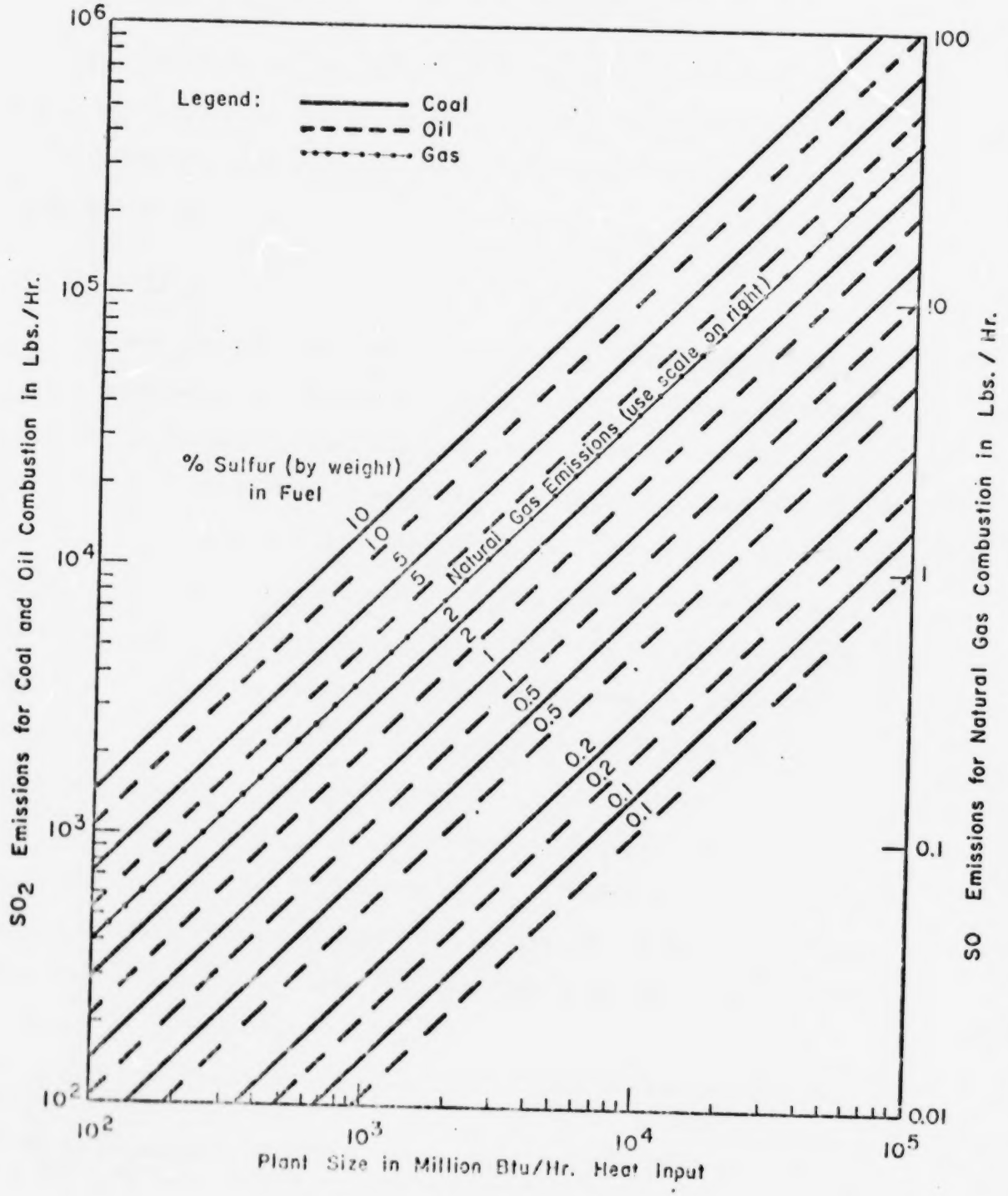

Fig. 4. SO_2 Emissions as a Function of Plant Size.

3.2 Control Regulations

The purpose of this section is to review existing standards of states and local areas for SO_2 emission control and, in particular, to identify the most stringent. The key sources of information were Refs. 25 and 35.

Oil-Fired Plants

The most stringent regulations on sulfur emissions presently in effect are those in New Jersey (Chapter X of the State Code), becoming effective on October 1, 1970, which require 0.4% sulfur content* for No. 4 oil and 0.5% for Nos. 5 and 6 oil** or their equivalent of 0.42 (for No. 4) and 0.52 (for Nos. 5 and 6) pounds of SO_2 emitted per million BTU gross heat input. A 0.5% sulfur content requirement has been in effect in Los Angeles County, California, since 1959 and several others since 1969. Even though the western utilities use natural gas, it is not available 100% of the time. Oil is their secondary fuel and they thus have been affected by the regulations.

Effective October 1, 1971, New Jersey regulations will tighten to 0.3% sulfur content for all residual (No. 4 or heavier) fuel oil combustion or the equivalent of 0.3 pounds of SO_2 emitted per one million BTU input. A similar regulation is proposed for New York at the same time (Ref. 25).

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* All percent sulfur contents referred to in this section are on a "by weight" basis.

** There is also a 0.2% sulfur content requirement on No. 2 oil, but to our knowledge utilities do not generally burn this.

Coal-Fired Plants

The most stringent regulations on sulfur emissions presently in effect for coal are those in several California counties (Los Angeles, for example) requiring 0.5% sulfur content of the fuel. However, power utilities are not affected by this, as they primarily burn natural gas and oil. A Boston area regulation requiring 0.55 pounds of sulfur (not SO_2) per million BTU heat input which is equivalent to about 0.7% sulfur content, became effective on October 1, 1970; however, to our knowledge, power utilities in that area all burn oil and therefore are unaffected. It appears that the most stringent present regulations on coal-fired plants that do affect power utilities are 1% sulfur content (or the equivalent), which are in effect in Maryland and Cleveland, Ohio, which are believed to be areas where coal is burned by power utilities (Ref. 26).

On October 1, 1971, a 0.2% fuel sulfur content regulation becomes effective in New Jersey for all new coal-fired plants, but only for existing plants having a rated hourly capacity less than 450 million BTU heat input (approximately 45 mw). Because oil is the chief fuel in New Jersey, this regulation will probably not affect utilities. At that same time, a 0.3% sulfur content regulation becomes effective in New York subject to approval of the proposed code.

Effective October 1, 1972, a 0.3% sulfur content regulation will be in effect in Philadelphia (Ref. 35). Since it is believed that some coal-fired plants are used there by utilities, this appears to the most stringent regulation on coal-fired plants forthcoming that will affect power utilities. Based on data in Ref. 35, it also appears that all other areas where coal-fired

plants are used by utilities will have at most a 1% sulfur content limit for the near future.

Gas-Fired Plants

So far as is known by us, there are no air pollution control regulations designated for sulfur emissions on gas-fired plants. Some of the regulations, the new Boston one effective October 1, 1971, for example, are stated in terms of fossil fuels, which covers coal, oil, and gas; however, the stated control limits are considerably higher than present emissions on commercial gas.

3.3 Control Technology

The usual classification of control methods for SO_x control is in terms of (1) using low sulfur fuels, (2) controlling the formation of SO_2 during combustion, and (3) removal of SO_2 in the flue gases. Only the first and third of these categories are considered adequately developed as potentially effective means of controlling SO_x emissions. The potential for control during combustion is well described in Refs. 2 and 21.

3.3.1 Use of Low Sulfur Fuel

If an adequate supply of low sulfur fuels were available at reasonable costs, the logical approach to SO_x control would be to switch to the use of low sulfur fuels. Unfortunately, and as is well known (Ref. 2), fossil fuel which is naturally low in sulfur content is less plentiful and costs

more than high sulfur fuel. Fuel desulfurization has not yet developed to the status where it is commercially feasible to supply all of the needed supply of low sulfur fuel.

Estimates of SO_2 control effectiveness and cost for several fuel switching strategies are presented in Table 6. The sulfur contents considered for the various fuels are those which appear to be most prevalent or most frequently cited in the literature. Operating costs given are based solely on added cost of the new fuel and, for the most part, were obtained from Tables 4-13, 4-14, and 4-15 in Ref. 2*. As fuel costs will vary considerably from region to region, costs were computed separately for each region for which corresponding data were available. From these were selected the minimum and maximum costs shown in Table 6. The intermediate value in parentheses represents the average increase in costs.

Gas

As is already well known, switching to natural gas is the most effective control strategy, but only for certain regions where cost of gas is competitive with coal or oil. For these regions where gas is actually less expensive than coal or oil, the "negative" operating costs for fuel switching were not shown, since most utilities in these areas are probably already taking advantage of this. The lower limit of zero costs

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*Even though the fuel prices in Ref. 2 are outdated, the differences in the costs of the various grades and types of fuels are considered representative of present values.

TABLE 6

EMISSION CONTROL EFFECTIVENESS AND COSTS IN USE OF LOW SULFUR FUELS FOR SO_2 CONTROL

Control Strategy	Availability	Emission Reduction (in %)	Capital Costs (in $/kw)	Operating[b] Costs (in mills/kwh)	Cost/Ton of SO_2 Eliminated (in $)
3.5% S Coal to Continuous NG	Presently available	99+	1-2[a]	0.2-(3.5)-5.7	8-(136)-220
3.5% S Coal to Interruptable NG	Presently available	99+	1-2[a]	0-(0.5)-2.4	0-20-96
2.5% S Oil to Continuous NG	Presently available	99+	1[a]	0-(2.7)-13.8	0-(148)-750
2.5% S Oil to Interruptable NG	Presently available	99+	1[a]	0-(1.4)-3.3	0-(77)-180
3.5% S Coal to 1% S Oil	Presently available	72	1[a]	1.7-(1.9)-2.2	92-(103)-119
3.5% S Coal to 0.5% S Desulfurized Oil	0-3 yrs.	86	1[a]	1.0-(2.4)-4.3	45-(109)-195
2.5% S Oil to 1% S Oil	Presently available	60	-	0.1-(1.1)-1.2	16-(173)-190
2.5% S Oil to 0.5% S Desulfurized Oil	0-3 yrs.	80	-	1.6	31
3.5% S Coal to 0.5% S Coal	Presently available	85	-	0.4-(1.2)-3.3	19-(57)-157

(continued)

TABLE 6 (Continued)

EMISSION CONTROL EFFECTIVENESS AND COSTS IN USE OF LOW SULFUR FUELS FOR SO_2 CONTROL

Control Strategy	Availability	Emission Reduction (in %)	Capital Costs (in $/kw)	Operating[b] Costs (in mills/kwh)	Cost/Ton of SO_2 Eliminated (in $)
3.5% S Coal to 1.4% Cleaned Coal	0-3 yrs.	60	-	0.30-(0.34)-0.38	20-(23)-26

[a] Costs listed were obtained from Ref. 2-11. These include only the cost of converting the boiler for burning the new fuel indicated; no estimates were made of fuel storage investment costs for the new fuel.

[b] Operating costs are based solely on added costs of new low sulfur fuel and thus do not include annualized capital costs which would be negligible.

thus represents the situation wherein, in a particular area, the two fuels would cost the same.

The interruptable gas service is less expensive because it can be supplied at times of less-than-peak-gas-load from the supplier. The cost advantage will be lowered when added storage costs are figured in, however, probably not to the extent that it would ever be higher. A combined strategy of using interruptable gas and a standby fuel such as low sulfur oil could be advantageous to some utilities; an example of this is given in Ref. 2.

The limitation of natural gas as a widely used SO_x control measure because of limited production and increasing demands is widely recognized. Ref. 14 even points out that some utilities that have historically burned natural gas are already in severe trouble with respect to obtaining additional natural gas for new power plants. Importation of liquid natural gas is frequently mentioned as a potential solution for SO_x control; however, the supply has not yet developed and costs are likely to be prohibitive in the near future (Ref. 14).

Low Sulfur Oil

Low sulfur oil is also in relatively short supply in the U.S. and will thus be limited in its use as an SO_x control measure to relatively few plants. Several utilities (Commonwealth Edison, Union Electric, Detroit Edison, Consumers Power, and the Cleveland Electric Illuminating) have obtained, or are in the process of requesting, import quotas for low sulfur residual oil (Ref. 14). Desulfurized oil appears to be competitive with natural low sulfur oils on a cost basis; however, desulfurization processes

are not yet developed to the point of insuring an adequate supply. It has been noted (Ref. 15) that the utilities in the New York area plan to rely primarily on low sulfur oil for meeting emission standards.

Low Sulfur Coal

Table 6 indicates that the use of low sulfur coal can be a competitive method of achieving relatively low SO_x emissions. Unfortunately, the availability of natural low sulfur coal is limited. Increased attention is now being given to coal cleaning, traditionally done primarily for removing fly ash and to meet BTU specifications, for purposes of removing sulfur. Sulfur occurs in coal in three forms: pyrite, sulfate, and organic. Only the pyritic portion, varying between 20% and 80% in most coals, can be removed by present processes. Cost estimates given in Table 6 for cleaned coal are based on an estimated premium per ton of $0.80 to $1.00 (Ref. 14). A good description of the status of coal cleaning is given in Ref. 10.

Coal gasification is also frequently mentioned as a possible solution to SO_x control. Much development is necessary if any of these processes are to become commercially feasible in the near future (Ref. 2).

3.3.2 Removal of SO_2 in the Flue Gas

Recognizing that reliance on low sulfur fuels is not likely to achieve the degree of SO_x control needed, many industrial firms have undertaken development of SO_2 flue gas removal processes. More than 50 such processes are under various stages of development throughout the world.

The need for investigating processes in other countries was ruled out with the discovery (Refs. 16 and 17) that U.S. developments were further advanced. In particular, it was learned that the German Reinluft process, which has been widely publicized as the most advanced, has experienced too many difficulties to be considered presently suitable for full-scale commercial operation. The Czechoslovakians are reporting far superior SO_2 removal efficiencies for a dry limestone injection than are U.S. developers of the process (Ref. 17); however, no data was available to substantiate this and the Czechoslovakian process was not considered. A number of the foreign processes in development are described in Ref. 18 with most of the foreign developments appearing to center in Germany and Japan.

A number of SO_2 removal processes are in various stages of development in the U.S., but quoting from a recent in-depth study report issued by a distinguished panel of experts (Ref. 8), "... contrary to widely held belief, commerically proven technology for control of sulfur oxides from combustion processes does not exist." This investigation has, in general, confirmed this; however, there are several processes in development which appear to be near-ready for commercial application and for which present cost and performance is adequately known to permit their use as a basis for proposed emission control regulations.

The processes considered are identified in Table 7 along with their availability status, SO_2 removal efficiency, and cost data. All of these are applicable to coal- or oil-fired systems. With regard to availability, it is to be remembered that these processes are not simple off-the-shelf items, but must be designed specially for each power generation

TABLE 7

EMISSION CONTROL EFFECTIVENESS AND COSTS FOR SO_2 FLUE GAS REMOVAL PROCESSES

Process	Availability	Capital[a] Investment $/KW	Operating Costs[a] mills/KWH		Cost/Ton of SO_2 Eliminated		Emission Reduction (in %)
			No Credit	Credit	No Credit	Credit	
Limestone injection/wet scrubbing (Combustion Engineering)	1-3 yrs.						
a. 55% load factor (retrofit)		8.3	0.57	N/A	23	N/A	90+
b. 75% load factor (new plant)		6.4	0.43	N/A	20	N/A	90+
Cat-Ox reheat-retrofit (Monsanto)	1-3 yrs.						
a. 55% load factor		36	2.56	2.17	107	91	85
b. 75% load factor		36	2.10	1.71	88	72	85
Dry limestone injection	1-3 yrs.						
a. 55% load factor		11.5[b]	0.81[b]	N/A	100	N/A	50
b. 75% load factor		11.5	0.65	N/A	81	N/A	50
MgO scrubbing/ (Chemico)	1-3 yrs.						
a. 55% load factor (retrofit)		19	1.25	0.84	50	33	90+
b. 75% load factor (new plant)		20	1.02	0.61	41	24	90+
Potassium Sulfite Scrubbing (Wellman/Lord)	1-3 yrs.						
a. 55% load factor		12.6 (A)	0.96	0.55	37	21	90
		13.5 (S)	1.05	0.79	44	34	85
b. 75% load factor		12.6 (A)	0.80	0.39	31	15	90
		13.5 (S)	0.88	0.62	37	26	85

(A) with acid recovery plant

(S) with sulfur recovery plant

TABLE 7 (Continued)

EMISSION CONTROL EFFECTIVENESS AND COSTS FOR SO_2 FLUE GAS REMOVAL PROCESSES

Process	Availability	Capital Investment $/KW	Operating Costs mills/KWH		Cost/Ton of SO_2 Eliminated		Emission Reduction (in %)
			No Credit	Credit	No Credit	Credit	
Cat-Ox integrated new plant (Monsanto)	2-5 yrs.						
a. 55% load factor		32	1.86	1.45	73	57	90
b. 75% load factor		32	1.44	1.03	57	41	90
Electrolysis (Stone and Webster/Ionics)	2-5 yrs.						
a. 55% load factor (retrofit)		17.5	1.26	0.83	46	31	95
b. 75% load factor (new plant)		13.0	0.83	0.40	33	16	95
Lime add-on/scrubbing (Bahco)	2-5 yrs.						
a. 55% load factor (retrofit)		13.8[/c]	1.17[/c]	N/A	44	N/A	95
Limestone add-on/wet scrubbing (Key West)	2-5 yrs.						
a. 55% load factor (retrofit)		8.9	0.62	N/A	26	N/A	85
b. 75% load factor (new plant)		7.1	0.48	N/A	20	N/A	85

TABLE 7 (Continued)

EMISSION CONTROL EFFECTIVENESS AND COSTS FOR SO_2 FLUE GAS REMOVAL PROCESSES

Process	Availability	Capital Investment $/KW	Operating Costs mills/KWH		Cost/Ton of SO_2 Eliminated		Emission Reduction (in %)
			No Credit	Credit	No Credit	Credit	
Sodium carbonate wet scrubbing (Peabody Engineering)	2-5 yrs.	8.3[/d]	1.53[/d]	N/A			70-99+
Sodium carbonate wet scrubbing (UOP Air Correction Div.)	2-5 yrs.	9.6[/e]	0.45[/e]	N/A			85

[/a] With the exception noted cost estimates are based on a 1000 mw plant size, 3.5% sulfur in coal, 18% annualarization rate of capital costs, heating value of coal @ 11,800 BTU/lb., and overall plant efficiency of 34.1%. Variable changes are itemized in detail in Ref. 2-10. When necessary, by-product credit was given on the basis of acid (100%) @ $10/ton and sulfur @ $20/ton.

[/b] Estimates based on 200 mw plant size, and 2% sulfur in coal.

[/c] Estimates based in 200mw existing plant only.

[/d] Data from Ref. 2-19 for cleaning 75% of the flue gas from a 200,000 lb./hr. (approximately equivalent to 20 mw plant) boiler.

[/e] Data from Ref. 2-20 for a 25 mw size plant.

unit or plant. Each of the processes represents a significant investment (from $5.00 to $20.00 per kilowatt capacity depending upon the process) from initiation of design to the beginning of on-line operation may require from one to several years, representing considerable money and time lost if not successful. None of the processes are developed to the point that the author would, in good faith, recommend for immediate commitment of a utility's funds if they expect to meet the indicated efficiencies on a continuous and reasonably trouble-free operation. The availability indicated for the processes represents when, based on available information, it is considered that a design of the process at a reasonable chance of successful performance could be initiated for a particular installation.

In addition to the processes identified in Table 7, several others that have gained attention in the literature and which appear to belong to the 2 to 5 year availability category are:

Process/Company	SO_2 Removal Efficiency
Molten Carbonate/Atomics International (Ref. 18)	95%
Ammonia Scrubbing/Ovitron (Ref. 18)	98%
Alkalized Alumina/Bureau of Mines (Ref. 18)	85%
Dry Absorbent/Babcock &Wilcox - Esso Research (Ref. 14)	90% (Objective)
Potassium Formate/Consolidated Coal (Ref. 14)	
Limestone Scrubbing/Babcock & Wilcox (Ref. 14)	90% (Objective)
Magnesia Scrubbing/Babcock & Wilcox (Ref. 14)	90% (Objective)
Alkaline Scrubbing/Research-Cotrell (Ref. 14)	

Cost data on these systems was generally too inadequate to report, therefore they were not included in Table 7.

SO_2 flue gas removal systems can generally be classified as either "throwaway", in which the sulfur compound removed is discarded, or as "recovery", in which a (hopefully) salable by-product is obtained from the recovered sulfur compound. These can be distinguished in Table 7 by

whether credit is included in operating costs for recovered sulfur products. (Recovery processes can also be used as throwaway processes if methods of discarding the recovered product are available.) All wet scrubber processes are generally throwaway processes unless the discarded material is salable for landfills, roadbuilding, etc.

The relationship of these processes to the particulates control problem is important. Generally, the use of a wet scrubber process such as the Combustion Engineering or Chemico processes eliminate the need for a precipitator, and the corresponding credit is usually factored into the cost calculations. On the other hand, it is known that the Monsanto process requires a particle removal of 99% efficiency or better (depending on fly ash content) for successful operation of the cat-ox process. The dry limestone injection process requires a very high capacity precipitator as it must remove the normally occurring particulates as well as the calcium sulfate solid particles formed in the boiler for capturing the sulfur.

As adequate descriptions of these processes are given in the literature, detailed descriptions of each of these processes are not given herein. Rather, the remaining discussion is devoted to some pertinent comparisons of the processes and general discussion regarding their applicability to meeting SO_x emission control regulations.

With the exceptions noted, all cost and SO_2 removal efficiency data were taken directly from Ref. 10, which was considered the most reliable source of data available*. With the exception of the dry limestone process, all have

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*Even though other cost data on some processes was reported, the wide difference in process application such as plant size and fuel sulfur content rendered it difficult to compare.

SO_2 removal efficiencies of 85% or greater. Also, the cost data indicates the capital investment will vary widely between about $8 and $36 per kilowatt for retrofitting existing plants and between $6 and $32 per kilowatt for new plants.

Operating costs are also seen in Table 7 to vary widely from about 0.4 to 2 mills per kilowatt-hour. The credit for by-products tends to make the recovery systems competitive with throwaway systems. Projected increases in sulfur product prices (Ref. 22) may possibly tend to favor recovery processes in the very near future.

Costs are sensitive to many factors, one of the main ones of interest being plant size. Generally, the dollars per kilowatt investment cost and the mills per kilowatt-hour operating costs will decrease with increasing plant size. Some good discussion and examples of how costs vary with fuel sulfur content, by-product prices, and plant load factors are given in Ref. 22.

As most utilities will be interested in experiences of others with the various processes, a listing of known applications of the processes in the 1 to 3 year availability category is given in Table 8. Note that several commercial-size (greater than 100 mw.) applications have been made to date, even though their purpose was as prototypes or engineering demonstration models. The 430 mw. application by Combustion Engineering soon to begin operation is the first known full scale, on-line commercial application. This process was sold several years ago at about the time the earlier processes were being installed. Even the manufacturer recognizes that there are further problems to be solved (Ref. 23). A by-pass provision will be included to prevent plant shutdown if difficulties develop. It is also known that Monsanto is actively marketing their cat-ox process; however, to date there are no takers (Ref. 15). The same source also indicated that several others, even

TABLE 8

SO_2 REMOVAL PROCESS APPLICATIONS

Combustion Engineering

Sept. 1968 to present, 140 mw, Meramac Plant, Union Electric Co., St. Louis, Missouri
Nov. 1968 to present, 125 mw, Lawrence Station, Kansas Power and Light Co., Lawrence, Kansas
Early 1971, 430 mw, Lawrence Station, Kansas Power and Light Co., Lawrence, Kansas

Monsanto

Aug. 1967 to July 1969, 15 mw pilot unit, Metropolitan Edison Co., Seward, Pa.
1972, 100 mw, Wood River Plant, Illinois Power, East Alton, Illinois

Tennessee Valley Authority (TVA)

Currently operational, 140 mw, Shawnee Power Plant, TVA, Paducah, Kentucky, (dry limestone process)
Jan. 1972, 150 mw, Shawnee Power Plant, TVA, Paducah, Kentucky, (limestone injection/wet scrubbing)

Chemical Construction (Chemico)

Currently operational, 150 mw, Boston Edison

Wellman/Lord

1967, 1 mw pilot plant, Gannon Station, Tampa Electric Co., Tampa, Florida
1968-1969, 25 mw and prototype, Crane Station, Baltimore Gas and Electric Co.

some of those in the 2 to 5 year availability category, have submitted proposals to utilities for sales.

There has been generally some concern over the availability of limestone (CaO) or dolomite (MgO) for the processes requiring these. Consideration of this (Ref. 24) has confirmed that adequate supplies are available. In fact, if half of all SO_2 removal was done with limestone processes, it is estimated that it would require at most the equivalent of 9% of present U.S. production. As limestone reserves are large with mining operations in 47 states, there should be little difficulty in meeting the demand.

No attempt is made to designate a best process. The suitability of a process will depend on many factors, and what is suitable for one plant may be entirely unsuitable for another.

4.0 NITROGEN OXIDES

Nitrogen oxides result from the fixation of nitrogen in the combustion process. Nitric oxide (NO) and nitrogen dioxides (NO_2), the latter in very small amounts, are the only oxides of nitrogen known to have significant equilibrium concentrations under boiler conditions. Although the low residence time of the gases permits only a small portion of the equilibrium concentration to be reached, the composition is essentially frozen as the gases cool rapidly and the concentration at stack conditions is many times the equilibrium concentration (less than 1 ppm). The term, NO_x, is generally used to represent NO and NO_2, both of which are known to play an important role in the chemistry of smog.

It was shown in Table 1 that steam electric power generation contributed about 4 million tons of NO_x in 1968 representing about 20% of the total from all sources in the U.S. The relative contribution to NO_x emissions from coal, oil, and gas combustion in the power industry is shown in Table 9.

TABLE 9

NO_x EMISSIONS FROM POWER UTILITIES IN THE U. S. IN 1968

Fuel	Emissions in Tons	% of Utilities Total
Coal	2,970,000[/a]	74.3
Oil	460,000[/b]	11.5
Gas	570,000[/b]	14.2

/a Data taken directly from Fig. 3-1 of Ref. 3.

/b Estimates computed from data in Ref. 3 and Fig. 1 of this volume.

4.1 Emission Levels

NO_x emission factors for coal, oil, and gas combustion are listed in Table 10. Also shown are emissions on a normalized BTU basis which were computed from the emission factor using fuel heat values of 13,000 BTU per pound of coal, 150,000 BTU per gallon of oil, and 1,000 BTU per cubic foot of gas. The emission levels listed would represent the pounds of NO_x emitted per hour for a typical 100 mw power plant. Emissions for a 1000 mw plant would be 10 times higher.

Note that the emission levels for the three fuels are ranked in the order: coal > oil > gas. Whereas this order is considered appropriate for small to intermediate combustion installations, more recent evidence has indicated that this order may, in fact, be reversed for large installations (Ref. 32).

TABLE 10

NO_x EMISSION FACTORS FOR COMBUSTION SOURCES (Ref. 3)

Fuel Type	Emission Factor (Ref. 9)	Emissions lbs. of $NO_x/10^9$ BTU
Coal	20 lbs. per ton of fuel	770
Oil	104 lbs. per 1,000 gal. of fuel	694
Gas	390 lbs. per million cubic feet of fuel	390

4.2 Control Regulations

Regulations on NO_x emissions were investigated with the emphasis on determining the most stringent emission standards. The only NO_x regulations known to us to date are those issued by various California areas and one prepared by New York. The most stringent standard is an absolute 140 lb. per hour limit on NO_x emitted by any new source currently in effect in several California counties (Los Angeles, San Bernadino, Orange, and Riverside) in the Los Angeles area (Refs. 25 and 33). This is an absurdly low standard for combustion and it is the general consensus that the primary purpose for its enactment was to prevent construction of any new fossil fuel plants.

The next most stringent regulation known for NO_x is the 250 ppm (vol.*) standard in effect in Ventura County, California, and is stated as follows:

Rule 59. Nitrogen Oxide Emissions

> A person in control of a stationary emission source operation shall not permit such operation to emit into the atmosphere gases exceeding in concentration 250 ppm (Vol.) nitrogen oxides (NO_x) calculated as nitrogen dioxide (NO_2) measured at the point of discharge, nor shall the emissions exceed 20 tons per day per source.

This regulation is reasonable as some present proposals for boilers guarantee a 250 ppm level (Ref. 11).

Other known regulations are a 500 ppm standard for Monterey County, California, (Ref. 34) and a proposed 50 ppm standard in New York which will apply only to new plants.

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* For comparative purposes, 250 ppm (vol.) would represent about 700 pounds of NO_x per hour from a 500 mw plant (Ref. 25).

4.3 Control Technology

The major factors considered to affect NO_x formation in combustion processes are amount of excess air, heat release rate, distribution of fuel and air and their mixing with combustion gases, and fuel type. The methods of controlling NO_x from combustion generally fall into the following categories:

(1) Fuel selection or switching

(2) Modification of operating conditions

(3) Modification of design features

(4) Flue gas removal.

In fuel selection or switching the aim is simply to select a lower NO_x producing fuel. According to the emission factors in Table 10 the logical choice is gas over coal or oil and oil over coal. However, it is now quite well accepted (Refs. 3, 32, and 34) that for large combustion installations gas combustion is the highe: emitter of the three types. This simply implies that NO_x emissions are dependent upon many things other than fuel type. The other major factors controlling the amount of NO_x formation in combustion processes as given above are mainly affected by boiler design and/or operating conditions.

The modification of operating conditions to reduce NO_x formation has received considerable attention in the past few years. The techniques receiving the most attention to date are:

(1) Low excess air firing - in which the air to fuel ratio is maintained below the level at which peak equilibrium NO_x concentration occurs. Reductions of 30 to 60% have been achieved with this technique in gas and oil combustion (Ref. 3).

(2) Two stage combustion - in which sub-stoichiometric quantities of

air are supplied at the first stage and complete burn-out is achieved in the second stage by injection of secondary air at lower temperatures. Reductions of 20% have been reported for this method (Ref. 3).

(3) Flue gas recirculation - in which dilution of air in the primary flame zone with recirculated flue gases lower the peak flame temperature causing lower NO_x formation. One test installation of a domestic heating unit achieved 50 to 65% reduction with this method (Ref. 3). More realistic levels for utility boilers are 30% (Ref. 32).

(4) Steam or water injection - which has an objective of lowering flame temperature. This method appears to have very limited effectiveness in NO_x reduction (Ref. 32).

(5) Combinations of the above.

Estimated NO_x reductions for these methods for various size plants and different fuel types is given in Table 11. Applications of these techniques to date have been limited primarily to gas- and oil-fired systems; therefore, the estimates given for coal are less reliable. Estimates of NO_x control costs for the various methods discussed above are presented in Table 12. The negative operating costs are reported to result from fuel savings.

The data in these tables indicate that a combination of techniques will be required to achieve large-scale reductions. This has been confirmed by applications to date which are discussed later.

Modification of boiler design features has been directed primarily toward the following features:

(1) Burner configuration, location, and spacing - in which the major objective is to achieve a configuration for increasing radiative heat transfer which affects the kinetics and heat release mechanisms.

TABLE 11

Public Utility Boilers: Estimated
% NO_x Reduction By Combustion Modifications (Ref. 32)

Boiler Size	LEA[1]	Two-Stage	LEA + Two-Stage	FGR[2]	LEA + FGR	Water Injection
1000 MW						
Gas	33	50	90	33	80	10
Oil	33	40	73	33	70	10
Coal	25	35	60	33	55	10
750 MW						
Gas	33	50	85	33	80	10
Oil	33	40	73	33	70	10
Coal	25	35	60	33	55	10
500 MW						
Gas	33	50	70	33	70	10
Oil	33	40	65	33	65	10
Coal	25	35	55	33	55	10
250 MW						
Gas	33	45	60	30	60	10
Oil	30	35	55	30	55	10
Coal	25	30	50	30	50	10
120 MW						
Gas	33	40	53	30	53	10
Oil	30	30	45	30	45	10
Coal	25	25	40	30	40	10

(1) LEA: Low excess air firing.

(2) FGR: Flue gas recirculation for NO_x control.

TABLE 12

Estimated Control Costs and Reduction of NO_x Emissions, For A 1,000-Megawatt Boiler Used 6,120 Hours/Year By Selected Methods and By Ton (Ref. 3)

Control method	NO_x reduction, %	Fuel used	Control cost/yr, $	NO_x reduction, tons/yr	NO_x control costs, $/ton
Uncontrolled (base case)	0	Gas	0	53,000[a]	0
	0	Oil	0	30,000[a]	0
	0	Coal	0	30,000[a]	0
Low excess air	33	Gas	- 95,000[b]	17,500	- 5[b]
	33	Oil	-297,000[b]	9,900	-30[b]
	25	Coal	- 79,000[b]	7,500	-11[b]
Two-stage combustion	50	Gas	0	26,500	0
	40	Oil	0	12,000	0
	35	Coal	299	10,500	29
Low excess air plus two-stage combustion	90	Gas	- 95,000[b]	47,700	- 2[b]
	73	Oil	-297,000[b]	21,900	-14[b]
	60	Coal	220,000	18,000	12
Flue gas re-circulation	33	Gas	202,000	17,500	12
	33	Oil	202,000	9,900	20
	33	Coal	202,000	9,900	20
Low excess air plus flue gas recirculation	80	Gas	107,000	42,400	3
	70	Oil	- 95,000[b]	21,000	- 5[b]
	55	Coal	123,000	16,500	8
Water injection	10	Gas	144,000	5,300	27
	10	Oil	179,000	3,000	60
	10	Coal	143,000	3,000	48

[a]Uncontrolled method, total NO_x emitted; no reduction.

[b]In instances wherein the installation of control equipment results in a savings, control costs are listed as negative numbers.

(2) Tangiential firing - which appears to operate at lower temperatures than other designs with reductions of 50 to 60% appearing achievable.

(3) Fluid bed combustion - which offers high heat transfer rates and low temperatures and which also offers the potential advantage of SO_x reduction.

Further development work is required on these techniques before they can be considered generally available as NO_x production methods.

To date, no flue gas treatment methods have been applied to NO_x control of power plants. It has been noted that 20 to 25% reduction of NO_x has been achieved with the limestone type flue gas scrubbing systems under development primarily for SO_x control (Ref. 3) and was confirmed for the Combustion Engineering system (Ref. 36). A good treatment of the status of the development of flue gas treatment methods is given in Ref. 32.

Applications

Most of the applications of NO_x control of boilers has been by Southern California Edison and the Los Angeles Department of Power and Water (LADPW). Tests were initiated in 1959 at the LADPW Scattergood Steam Plant which was emitting over 650 ppm of NO_x at full load for both gas and oil firing. The success with two-stage combustion experimentation prompted LADPW to convert two units to two-stage combustion which resulted in an average NO_x reduction of 27% (Ref. 34). Whereas the later experiences of LADPW in NO_x control were not pursued in depth, the experiences of Southern California Edison cited below are considered to best represent the potential of NO_x control (Ref. 11).

The major source of information on Southern California Edison (SCE) NO_x controls was the contact identified as Ref. 37. SCE uses about 80% gas

and 20% oil. All units except one are achieving emissions below 250 ppm NO_x which represents about 80% efficiency of NO_x reduction from levels before controls were applied. Two-stage combustion and air deficiency of 85% of stoichiometric for the first stage are the primary control measures. Six units of Combustion Engineering, Inc. design have been supplied with flue gas recirculation and some of these are achieving 150 ppm of NO_x levels. Additional operating costs due to NO_x controls are negligible. Similar control measures are also applied when burning oil which is 0.3% sulfur content, (Indonesian oil) and similar success with NO_x control has been experienced. NO_x emissions with oil-firing have been noted to be more sensitive to air. A tendency has been noted for increased carbon monoxide emissions with NO_x controls; however, no data are available. No information was available on hydrocarbon emissions before and after NO_x control; however, it was noted that controls during oil-firing could produce some increase in hydrocarbons.

Even though it is not the best controlled plant for NO_x emissions, the Moss Landing Plant of Pacific Gas and Electric (PG & E) is considered below because of the unique problems with NO_x emissions and their solution. The major source of information for this discussion was Refs. 11, 34, and 38. Two 750 mw (gas- and oil-fired) units were added to the Moss Landing Plant in 1968 which were discovered to be consistently emitting 1200 to 1300 ppm of NO_x during gas-firing (at 6% excess air) but consistently less than 350 ppm of NO_x during oil-firing. PG & E had planned to rely on gas-firing 95 to 98% of the time and had anticipated NO_x below the 500 ppm set by regulation. The high NO_x emissions clearly established that simply relying on gas in place of oil was not necessarily an effective NO_x abatement procedure.

The solution for reducing NO_x emissions was achieved with a two-stage type of combustion. The lowest burners in each cell (of three) were fired with a deficiency of air while increasing the air to the upper burners with installed NO parts. Fuel was also cut off completely to the topmost burner in each cell. Excess oxygen was effectively reduced to 1% at full load. With the modifications the NO_x emissions were maintained between 150 and 250 ppm, or about an 85% decrease from initial levels. Increased operating costs due to the NO_x control measures resulted only from about a 1% decrease in plant efficiency or equivalent to about 0.15 mills per kilowatt-hour. The actual capital cost of applying the controls at the Moss Landing Plant was not available; however, a rough estimate of $50,000 was obtained from Ref. 37 for typical plants of the size of Moss Landing.

PG & E plans include further change of the boiler design to include a larger flue gas recirculation primarily as a protective measure to the boiler rather than for NO_x control.

No increase in carbon monoxide nor hydrocarbon was noted with application of the NO_x control measure at the Moss Landing Plant.

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